CITY OF ANN ARBOR
100% RENEWABLE ENERGY OPTIONS ANALYSIS

September, 2023

Executive Summary

The City of Ann Arbor has committed to using electricity generated only by renewable sources by 2030. The current growth trajectory of renewables in Ann Arbor's electricity supply will leave the City well short of 100% renewable energy (RE) in 2030. Achieving the 2030 goal will depend on the City's ability to mobilize additional RE resources and to implement the most favorable organizational structures to deploy them.

The City of Ann Arbor retained the team of 5 Lakes Energy, SunStore Energy, Potomac Law Group and NewGen to explore potential energy option pathways to achieve the A^2ZERO 2030 vision. We analyzed several energy supply options and organizational structures through the lens of the A^2ZERO Energy Criteria and Principles (Appendix 1). We identified tradeoffs among the risks and benefits presented by the Energy Options and organizational structures and the A^2ZERO Energy Criteria and Principles. We found several plausible, if challenging, pathways for the City to achieve its 2030 A^2ZERO energy goals by deploying portfolios of energy resources that in each case depend on the applicable modeled utility structure. In this report, we present the risks, benefits, and tradeoffs of these pathways in a way intended to support decision making by the City's elected leaders and participation by the public and other stakeholders.

A^2ZERO's required pace of behind-the-meter (BTM) photovoltaic (PV) and building energy efficiency improvements are ambitious and largely unprecedented, regardless of the utility structure the City pursues. Even if the City achieves a high level of success with distributed energy resources, some non-renewable electricity will almost certainly remain in Ann Arbor's electrical grid in 2030, requiring purchase of virtual assets through such mechanisms as renewable energy credits (RECs) or Virtual Power Purchase Agreements (VPPAs) to make up the difference.

How much electricity will Ann Arbor need in 2030?

To model the City's options for 100% renewable electricity in 2030, we first estimated how much electricity will be needed. We used public data sources to estimate electricity loads in Ann Arbor today. We then projected 2030 electricity usage based on A^2ZERO program goals including energy efficiency and electrification of buildings and vehicles. See Figure 1: Ann Arbor Residential and Commercial Loads, 2024-2044.

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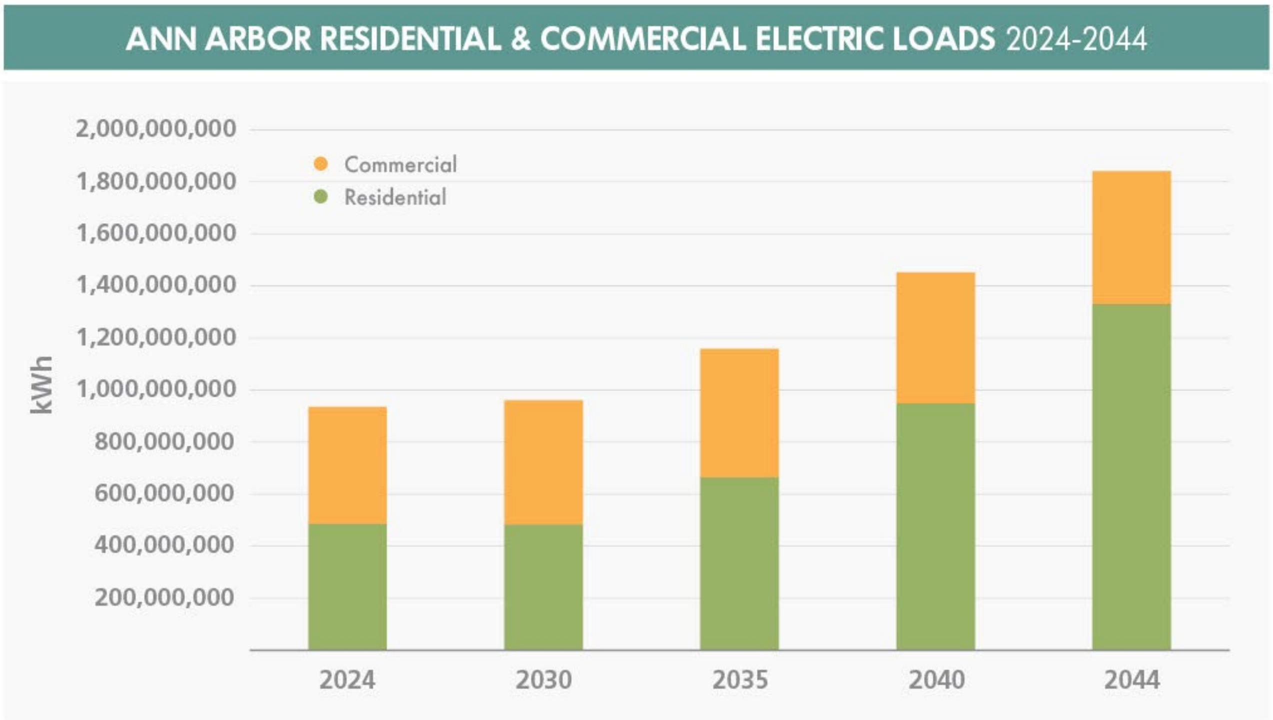
Figure 1: Ann Arbor Residential and Commercial Loads, 2024-2044



Electrification and energy efficiency will largely offset each other through 2030 if the A^{2}ZERO goals are met, keeping total usage slightly under 1,000,000 MWh/year.[1] After 2030, however, continuing electrification is likely to greatly increase how much electricity is used compared to today, with the increase driven mostly by residential customers. Our detailed modeling examined only how to meet 2030 loads. We provide projections for later years to serve as context and as inputs to long-term capital spending projections as part of our evaluation of utility structure options.

Current and Planned Renewables will not Supply 100% Renewable Electricity in 2030

To estimate how much more renewable electricity will be needed in 2030, we needed first to estimate how much will likely be available in a Business As Usual (BAU) scenario. We divided this assessment into two parts. First, we projected how much renewable electricity DTE will provide to Ann Arbor customers under its default residential and commercial tariffs. Then, we projected how much renewable electricity will be provided through DTE's Voluntary Green Pricing (VGP) program, MI Green Power (MIGP), and through RE efforts of the City, property owners and Ann Arbor Public Schools.

Under Michigan's Renewable Portfolio Standard (RPS), DTE is required to provide a minimum of 15% renewable electricity to all customers. DTE recently committed, as part of the settlement of its Integrated Resource Plan before the Michigan Public Service Commission (MPSC) to voluntarily increase that number to 40% by 2035. Although DTE did not set a specific 2030 interim target, we linearly interpolated between today and 2035's target that DTE will provide 35% RE to all customers in 2030.

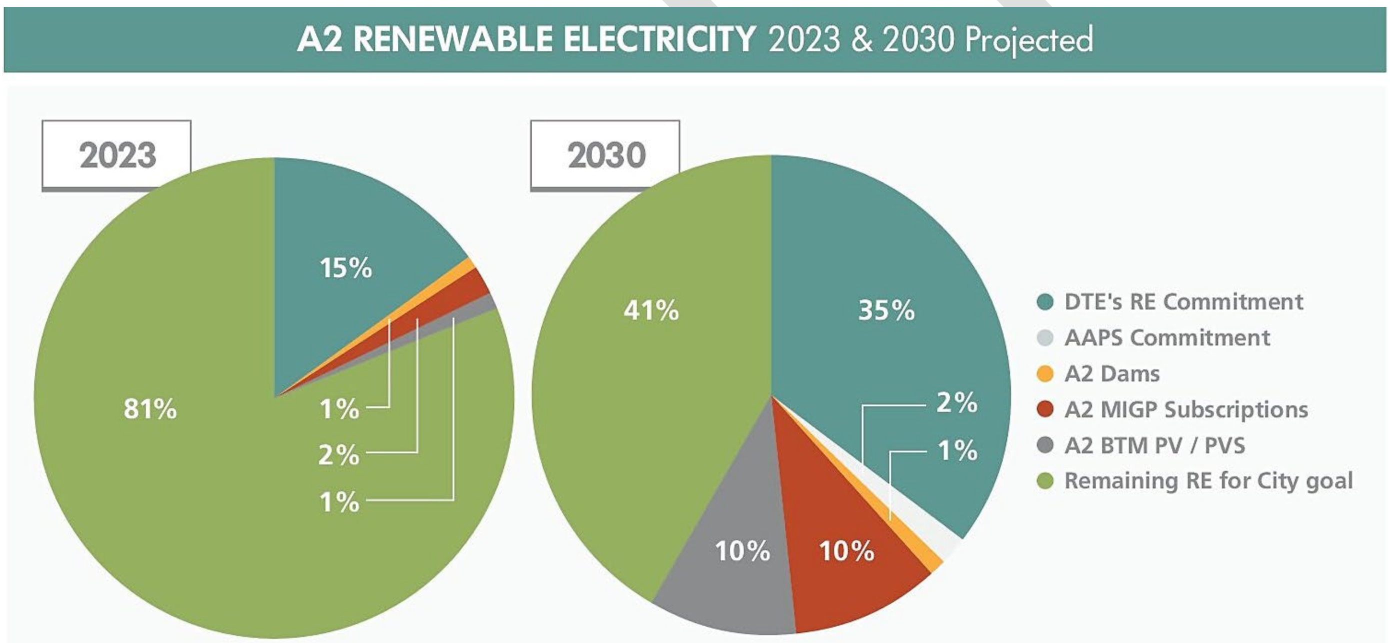
[1] This figure excludes electricity used by University of Michigan (U of M), because U of M is independent of the City and can choose its own energy goals and methods. Fortunately, U of M also has ambitious climate goals that are reasonably resonant with the City's.

That target leaves a 65% renewable electricity gap to be closed by DTE voluntary programs and customer RE initiatives in 2030.

Next, as shown in Figure 2, we projected how much renewable electricity will be provided to Ann Arbor through voluntary initiatives:

- We estimate that DTE's voluntary MIGP, through which customers can subscribe to receive up to 100% RE, will account for 10% of Ann Arbor's load in 2030. The Wheeler Center Solar Project development is included with MIGP. This estimate is based on current enrollments and pricing trends, extrapolated out to 2030.
- We assume that Ann Arbor Public Schools will meet its target of 100% renewable electricity by 2030 and count the renewable energy credits from locally owned dams, together which cover another 3% of the City's total load.
- We estimate that BTM PV, and PV with battery storage (PVS), will account for another 10% of the City's 2030 load, based on current installations and growth rates.

Figure 2: Renewable Electricity Sources in 2023 and projected 2030



NB: figures sum to less than 100% owing to rounding.

In sum, we estimate that currently active or firmly committed DTE and other RE initiatives are likely to deliver about 59% of the City's total electricity usage by 2030 from renewables. To achieve 100% RE in 2030, the City must come up with a plan to secure the remaining 41% of its annual electric load from renewable sources. This remaining goal amounts to approximately 578,000 MWh per year.

This projection is our BAU estimate; more colloquially, it is our projection for 2030 assuming DTE, Ann Arbor and its residents and businesses were to effectively implement the programs and commitments that exist today. Its attainment is hardly assured: DTE's substantial renewable energy scale-up, and our projected future enrollments in its voluntary MIGP program are both challenging targets. Likewise, the City's active BTM PV/PVS program (Solarize) and the Wheeler Center Solar projects are accelerating the RE transition, but further accelerated growth of Solarize is not guaranteed. Our scope of work was not to solve all logistical challenges: we assumed that current trends and program commitments will meet their stated objectives in 2030. In the same way, we assumed that the 2030 A^{2}ZERO strategies will attain their stated 2030 objectives, even though they also will be very challenging. Thus "Business As Usual" may not adequately suggest uncertainties arising from the challenges of meeting objectives of various existing and promised DTE, City and other programs, but it is a common term that we find useful, nevertheless.

We later examine how these options may deliver more RE than projected here; Figure 2 only shows our estimate of how much they will contribute if current commitments are implemented successfully.

Energy Options to Reach 100% Renewable Electricity by 2030

To reach 100% renewable energy by 2030, the City must plan to mobilize additional resources to further supplement or replace DTE's resources. We examined several Energy Options that may help close the gap and estimated the unit cost of each of them.

The renewable Energy Options we analyzed were:

DTE's MI Green Power Program (MIGP; generically, Voluntary Green Pricing, or VGP) allows customers to subscribe to receive a higher percentage of renewable electricity than provided in DTE's default tariffs, up to 100% RE. The MIGP rate is an adder to the customer's base tariff rate, based on the differential cost of additional renewables versus DTE's existing generation fleet. The adder formula currently results in MIGP customers paying less than non-MIGP customers, but pricing will change as DTE adds resources to its MIGP program. Large DTE customers may have the option to request that DTE develop and operate PV or wind at a site the customer chooses, provided that customer agrees to be responsible for the costs of any electricity not sold to other customers. The City's Wheeler Center Solar Project installation is being pursued under this "customer requested" option.

Behind-the-meter (**BTM*****)* Photovoltaics (PV) and PV with battery storage (PVS)** are installed on customers' premises on the customer's side of the electric meter. When PV generates more electricity than the customer's load, and they do not have battery storage, the surplus electricity outflows to the grid. If a customer has PVS, surplus electricity is often first utilized to charge the battery system. Customers are typically allowed to design PV systems as large as their annual net usage but not larger.

Community Solar is a development model that allows customers to offset their electricity usage from a specific solar PV plant. It is generally of greatest interest to customers who cannot install PV on their rooftops or elsewhere on their properties. There is no existing statewide community solar policy, and there is no existing DTE policy to allow community solar, so the community solar model applied in this study is derived from draft state legislation. This model contemplates a third-party owner (TPO) developing and owning a PV system and selling subscriptions to customers, who will receive a bill credit based on the value of the PV electricity produced. Community solar models often sell the Renewable Energy Credits (RECs) separately from the generated electricity to reduce customer cost, but the City's 100% RE target would require the RECs to stay in Ann Arbor; therefore, our model bundles the value of the RECs with the electricity. The feasibility of this option will depend on passage of appropriate legislation.

Power Purchase Agreements (Traditional and Virtual)*:* Traditional Power Purchase Agreements (PPAs) are direct contracts between power producers and customers to sell electricity at a predetermined price over a fixed period. PPA contracts sell power and any associated environmental attributes directly to the customer. Since under current state law Ann Arbor cannot buy power from a supplier other than DTE, Traditional PPAs are not currently an option. Like Traditional PPAs, Virtual PPAs (VPPAs) are an agreement between an electricity producer and customer, but VPPAs allow the buyer to take delivery only of the environmental attributes of the renewable energy generation. VPPAs can thus enable the building of new RE facilities when there is no direct off-taker for the energy they produce, thus making more RE generation economically feasible. VPPA RECS are delivered to the customer and VPPA electricity is then sold on the open market to other customers. VPPAs often include financial mechanisms to settle differences between a set price for the power produced under the VPPA and the actual market price when sold on the energy market. There is a limited but available market for fixed price VPPAs. Ann Arbor can thus enter into VPPAs that allow purchase of the renewable attributes of the electricity generation source without having also to receive the electricity itself.

***National RECs*:** Renewable Energy Credits (RECs) represent the renewable energy attributes or benefits associated with generating RE. They are separate from the physical electricity, which is often sold to the grid or somebody else without the green attributes attached. RECs are denominated in terms of the megawatt-hours of electricity they represent. Their market price depends on several factors, including generating source, additionality and strength of verification, location, and length of contract. A REC purchase resembles a VPPA contract, except the REC purchase conveys only the REC and not the physical electricity. The quality of National RECs varies significantly in terms of additionality and verifiability. In MI, since the utilities have already met their state-imposed RE targets, the upshot is that VPPAs generally enable the building of a new RE resource, while purchase of Michigan RECs generally comes from existing RE resources. However, we assume that Ann Arbor would buy only RECs with strong additionality and verification, which might entail buying out-of-state RECs. Accordingly, we model the national REC market.

Virtual Power Reduction Agreements (VPRAs) offer a method for creating RECs from energy efficiency projects, rather than producing renewable electricity, under a special provision of Michigan's energy law. The logic is that energy efficiency improvements displace carbon emissions from existing generating resources comparable to renewable energy displacing fossil-fuel based energy from the grid.

In addition to evaluating energy procurement options, we also evaluated three models of utility organizational structures within which the Energy Options might be implemented: continuing with DTE as primary provider (DTE+), starting a Sustainable Energy Utility (SEU), and starting a Municipal Energy Utility (MEU). Because these are organizational structures, rather than ways to generate RE or RECs, we evaluate them separately from the Energy Options.

Energy Options Marginal Costs

In Figure 3, we present a comparison of all Energy Options' marginal energy costs to purchasers compared to DTE's retail energy costs. "Purchasers" for any given energy option may comprise more than one entity: for example, Ann Arbor ratepayers may pay for DTE electricity, but the City budget might bear the cost of RECs that offset the carbon embedded in DTE's electricity. We show total marginal costs paid by all entities in Ann Arbor combined, including residential and commercial ratepayers and the City budget, without differentiating who would pay them.

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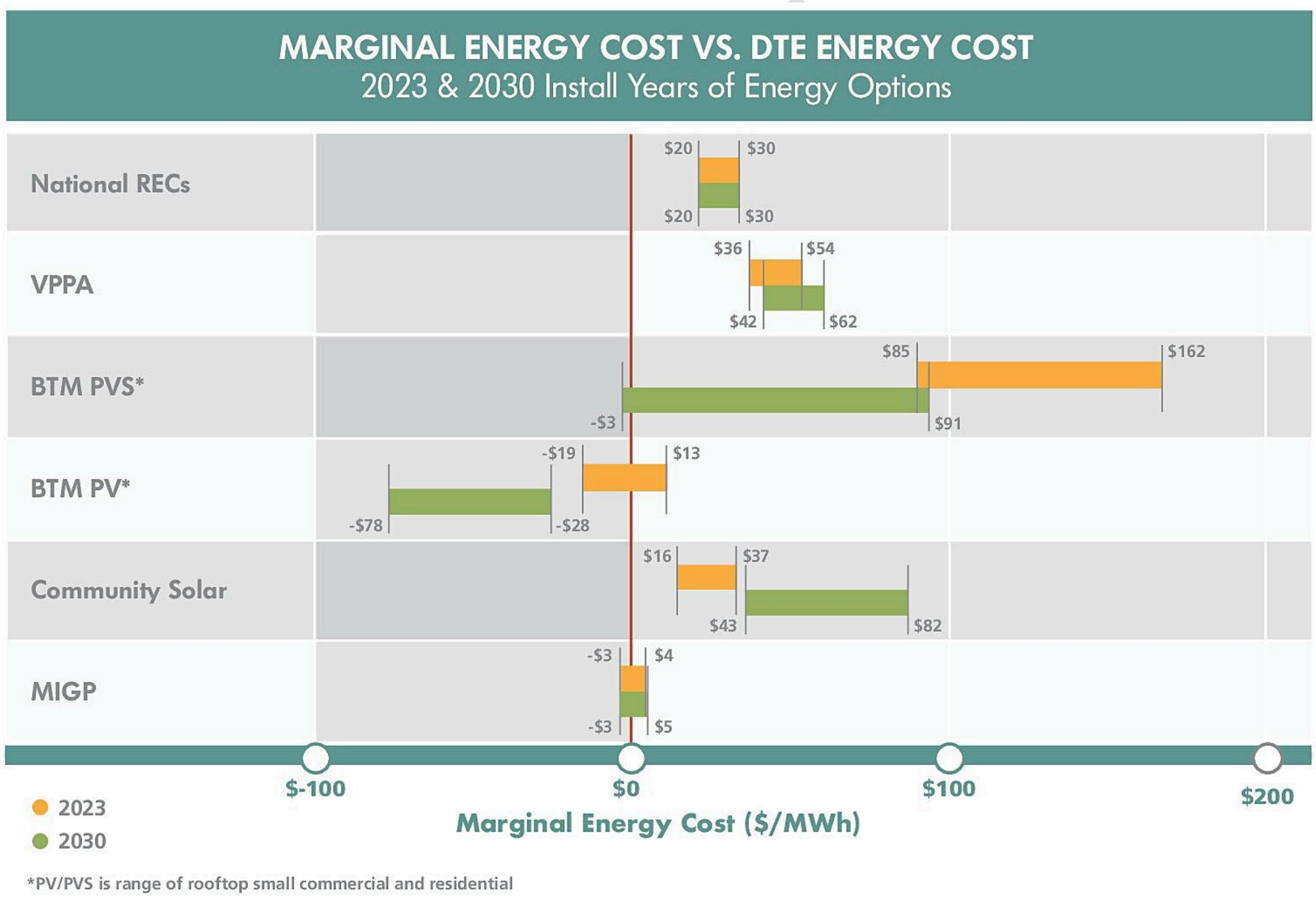
Figure 3 shows a range of marginal energy costs for Energy Options installed compared to DTE's 2023 rates. It then projects these costs again for new Energy Options executed in 2030. The Energy Options are positioned at various physical locations on the grid, such as behind-the-meter (BTM) and in front-of-the-meter (FOM). The net costs for BTM Energy Options are presented as the difference between the levelized energy cost of the BTM Energy Options and the energy portion of DTE's retail electricity price. The net costs for FOM Energy Options are the levelized energy costs of acquiring the Energy Options versus DTE's acquisition costs through MISO's energy market.

Figure 3: Projected marginal costs of Energy Options vs. DTE costs



Energy Options Satisfy the A²ZERO Energy Criteria and Principles to Varying Extents

The City adopted the A²ZERO Energy Criteria and Principles to guide energy policy decision making. The Energy Criteria must all be satisfied in any energy pathway the City chooses; the Energy Principles may be balanced against each other. The City's explanation of the A²ZERO Energy Criteria and Principles is provided in Appendix 1.

We developed a rubric for evaluating performance against the A²ZERO Energy Criteria and Principles – explained in our report – and arrived at the following matrix. Our rating rubrics for the Criteria and Principles are explained starting on page 39. Our explanations of how we applied the rating rubrics to each organizational structure are included in the respective Energy Options analyses starting at page 58.

Table 1: Alignment of Energy Options with A²ZERO Energy Criteria and Principles

ALIGNMENT OF ENERGY OPTIONS with A²ZERO Energy Criteria

CRITERION	MI GREEN POWER	(V)PPAs	NATIONAL RECs	COMMUNITY SOLAR	BTM PV& PVS	VPRA
Reduce GHG	YES	YES	YES	YES	YES	YES
Additionality	YES	YES	YES	YES	YES	YES
Equity & Justice	GOOD	FAIR	POOR	POOR	FAIR	EXCELLENT

ALIGNMENT OF ENERGY OPTIONS with A²ZERO Energy Principles

PRINCIPLE	MI GREEN POWER	(V)PPAs	NATIONAL RECS	COMMUNITY SOLAR	BTM PV& PVS	VPRA
Enhance Resilience	POOR	POOR	POOR	FAIR	GOOD	FAIR
Start Local	FAIR	FAIR	POOR	GOOD	EXCELLENT	GOOD
Speed	FAIR	EXCELLENT	EXCELLENT	POOR	GOOD	POOR
Scalable & Transferable	GOOD	EXCELLENT	EXCELLENT	EXCELLENT	EXCELLENT	FAIR
Cost Effective	EXCELLENT	POOR	POOR	POOR	EXCELLENT	POOR

The portfolio must satisfy the Energy Criteria and balance the Principles in a way acceptable to the City. RECs, for example, satisfy the Speed principle, but do little or nothing for Equity and Justice, Cost-Effectiveness and Resilience in Ann Arbor. BTM PV/PVS, while serving the Start Local principle very well, has maximum potential contribution of 27% of Ann Arbor's load in 2030 and will probably contribute much less. To achieve reliable supply and satisfy the Energy Criteria, while satisfactorily balancing the Principles, a portfolio of energy resources will be needed.

Stacking of Renewable Energy Options

We studied many scenarios and present only what in our estimation are reasonable and achievable example scenarios to illustrate how the Energy Options may be "stacked" to reliably supply energy needs while attempting to best satisfy the A^{2}ZERO Energy Criteria and Principles. Our scenarios show that the City can technically meet its goal of 100% renewable electricity by 2030 with varying combinations of Energy Options. The choice of pathway will depend on how the City chooses to balance costs and risks against the Energy Criteria and Principles, while adapting to external factors.

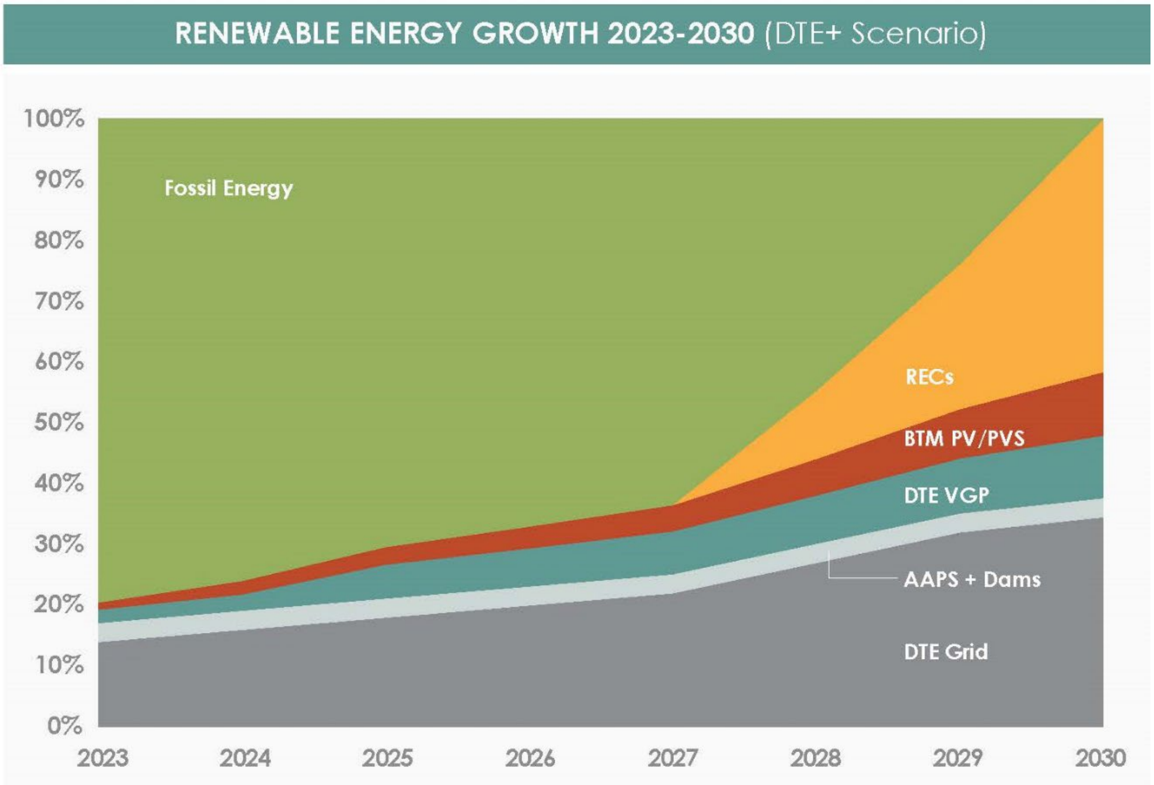
Stacking is necessary owing to the growth potential for any given energy option, and the diversification inherent in stacking also provides risk mitigation in case there are unforeseen limitations to any option. Some Energy Options are already active in Ann Arbor, such as BTM PV/PVS and customer MIGP. However, it is improbable that sufficient BTM PV/PVS could be installed by 2030 to achieve the balance of RE not provided by DTE. We modeled the growth of existing and new Energy Options based on reasonable economic projections, technical conditions, and customer adoption behaviors. RECs are anticipated as useful Energy Options, either through competitive VPPAs or National RECs, to close the gap remaining despite the adoption of more local Energy Options. Figure 4 shows a stack of Energy Options favorable for a baseline scenario called DTE+, which we explain in more detail below.

Scenarios for Stacking under Different Organizational and Policy Assumptions

We present three scenarios to illustrate stacking options, which feature two utility structures and one policy variation:

- DTE+: continuation of DTE's current role, plus commitment of new City programmatic and financial resources to close the 2030 renewables gap. The City would aggressively promote and support deployment of BTM PV and PVS, follow through on development of the Wheeler Center Solar Project, purchase RECs or VPPAs to offset remaining fossil fuels, and pursue other A^{2}ZERO 2030 targets, within existing City structures and departments.
- SEU and DTE+: Ann Arbor would launch a supplemental Sustainable Energy Utility to promote, organize and finance distributed energy resources around the City. DTE would continue as the City's main provider of electricity with obligations to serve all customer loads. Assumes continuation of 2023 policy/regulatory environment.
- SEU and DTE+ and Community Solar: the SEU scenario plus a change in state or DTE policy allowing Community Solar. We modeled this hypothetical scenario because community solar is an energy option the City wishes to pursue but which is not otherwise included in our modeling under current policy assumptions; and we assess there is positive momentum in the Legislature to pass enabling legislation.

Figure 4: Example scenario (DTE+) integrating many Energy Options to achieve 100% RE by 2030.



We show in Table 2 how the three Energy Options scenarios technically can achieve 100% RE by 2030. We present identical growth trends for MIGP adoption and BTM PV/PVS adoption for all three scenarios, to illustrate differences between the utility structures and statewide policy impacts. The rate of growth for MIGP and BTM PV/PVS is significant over the next seven years. DTE MIGP (City) indicates assumed contribution of the Wheeler Center Solar Project to municipal government loads. Additional BTM (SEU) indicates potential contributions of an SEU to growth in BTM PV/PVS, as distinguished from BTM PV/PVS which would not involve SEU financing. If any of these options grows more rapidly, City REC costs could decrease. We modeled a combination of both VPPA RECS and National RECs that would be necessary to achieve the 100% RE goals by 2030.

It may be possible, though challenging, to achieve the 2030 A^{2}ZERO goals following any of these pathways. Many Energy Options are compatible and flexible in their growth, should the City desire to focus resources in particular areas. We also note each energy option has unique differences in how they may be deployed and evaluated based on their costs, risks, and performance against the A^{2}ZERO Energy Criteria and Principles.

Table 2: Energy Options Contributions in Three Scenarios

2030 100% RE Three Energy Options Scenarios			
RE Option Load Share	DTE+	SEU & DTE+	SEU & DTE+ & Community Solar
DTE Grid, AAPS, Dams	38%	38%	38%
DTE MIGP	9%	9%	9%
DTE MIGP (City)	2%	2%	2%
BTM PV / PVS	10%	10%	10%
Additional BTM (SEU)	0%	8%	8%
Community Solar	0%	0%	6%
RECs (VPPA, National RECs)	42%	34%	27%
Total	100%	100%	100%

Energy Option Scenarios Costs to the City

We focused the summary cost tables for these scenarios on costs that would directly flow through City budgets rather than all costs assumed by Ann Arbor electricity customers. For City stakeholders it is important to distinguish costs that may initially flow through the City budget and be recovered from the costs that will not be recoverable. From a broader perspective, whether an energy cost is covered by taxpayers or ratepayers in Ann Arbor may be an unimportant distinction, but from a municipal budgeting perspective the costs that "stick" to the municipal budget are consequential. Therefore, we partitioned the Energy Options into three cost categories:

No costs to City: BTM PV/PVS with customer ownership or third-party ownership, customer MIGP, and Community Solar. The City has developed programs to bolster adoption and bears some staffing costs, but equipment and electricity costs are borne by the customers.

Costs Recoverable to City: We classify costs as recoverable under two conditions. First, if municipal operations use electricity generated by BTM PV/PVS installed at City/SEU cost, then the rates they pay for that electricity will include cost recovery. Second, if the City pays for SEU subscribers' PV/PVS projects, the costs are ultimately recouped from these electricity subscribers through their monthly payments to the SEU. This approach distinguishes between costs that increase the City's budget on a net basis, versus costs the City recovers from ratepayers (including its own departments). These programs can incur significant upfront costs, such as financing a portfolio of BTM PV projects across municipal properties and ownership of SEU assets through debt financing; upfront costs are recovered from customers, over time, via the rates they pay. This category may also include annual energy costs such as SEU management of assets with third-party owners that may have a PPA contract with the SEU.

Costs Non-Recoverable to City: VPPA, National RECs, VPRA. These costs include Energy Options that achieve RE accounting goals without providing physical electricity services to customers in Ann Arbor.

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Additionally, MIGP serving municipal government loads and Wheeler Center Solar Project may increase net costs in the City budget, depending on project costs and changes in the MIGP tariff rider over time.

In Table 3 we compile cost data to show City RE costs for the year 2030 and a sum of RE costs from 2023-2029. In the SEU scenarios below, we assumed the SEU developed a portfolio with 25 MW of PV-only and 25 MW of PVS. The recoverable costs grow significantly in the SEU scenarios, because the SEU financing costs flow through the City but are fully recoverable through subscribers' electricity bills. The non-recoverable costs are effectively the 'net costs' to the City and would ultimately be borne by taxpayers. We observe the net costs are lower in the SEU scenarios than in the DTE+ scenario and note that SEU portfolio expenses are likely to have positive direct and indirect economic impacts in the region. We present the SEU financing obligation later in this report in Table 4.

Table 3: Costs to City Budget of Energy Scenarios

City Costs for Three Energy Options Scenarios			
City Cost Categories ($000s)	**DTE+**	**SEU & DTE+**	**SEU & DTE+ & Community Solar**
2030 CITY COSTS			
City Costs	$17,890	$24,679	$22,431
Recoverable Costs	$2,327	$12,145	$12,145
Non-Recoverable Costs	$15,563	$12,534	$10,285
2023-2029 CUMULATIVE CITY COSTS			
City Costs	$17,728	$49,098	$48,021
Recoverable Costs	$5,745	$38,787	$38,787
Non-Recoverable Costs	$11,983	$10,311	$9,234

We do not recommend how the City should choose among these utility structures. All three offer pathways to 100% renewable electricity. The MEU would very likely not launch on time to contribute to the 2030 goal of 100% renewable electricity. However, if the City chose to study the MEU option further, it could deploy energy options that contributed toward the 2030 goal and that could be rolled into the MEU structure if it were to launch later.

Instead, our goal here is to provide enough information to help facilitate a robust public discussion of how best to trade off costs, risks and adherence to the A^{2}ZERO Energy Criteria and Principles. For example, the principles to "Start Local" and "Enhance Resilience" are probably most favored by a focus on behind-the-meter PV and PVS resources within the City, but virtual resources such as VPPAs and RECs rate better for "Speed" because they could contribute much more load carrying capacity by 2030. We discuss these tradeoffs further below. We foresee similar tradeoffs in the choice of utility structures.

SEU Analysis: Summary

A Sustainable Energy Utility (SEU) would be a municipal utility supplemental to the existing electric load-serving entity (DTE). The SEU would operate as an independent City utility with similar operations as other main public services, such as the Ann Arbor Water Utility. While SEUs are not common around the US, Ann Arbor could follow the path blazed by operational SEUs in other parts of the country. We assume the SEU could take a lead role in advancement of many A^2ZERO 2030 goals related to energy efficiency, electrification, and non-electricity renewable energy, but we focused our scope of work on renewable electricity solutions. We expect Ann Arbor's SEU model to observe all existing laws and regulations, build development policies, and establish a financial plan that adheres to Ann Arbor's vision.

Ann Arbor provided a vision of a phased SEU. In Phase 1 work, the SEU focuses on accelerating the deployment of BTM PV and PVS portfolios with minimal network connections. These portfolios are effectively independent installations at subscribers' sites where the storage's primary use case in a PVS project is for backup power. Our financial analysis focuses on portfolios of Phase 1 deployments. We found an SEU Phase 1 could be feasible within a range of technical and economic conditions. A Phase 2 portfolio would significantly change an SEU deployment by establishing microgrid capabilities. Phase 2 work would include building a network of physical equipment connecting subscribers' sites, all BTM, that would enable SEU subscribers to share PV and PVS resources during grid outages or when choosing microgrid operations at select times. We provide a preliminary technical and regulatory analysis of Phase 2 concepts but do not project financial results. There is wide variation in microgrid designs that significantly impact overall costs. A future SEU Phase 2 study could examine microgrid concepts in technical and financial detail.

For the scenario presented in Figure 5, we assumed the SEU would serve subscribers that would not necessarily be installing PV/PVS on their own, and the SEU could achieve 50 MW of additional solar in Ann Arbor by 2030. In this scenario, the SEU would stimulate deployment of more BTM PV and PVS primarily by making it easier (both financially and operationally) for property owners and subscribers. These property owners may live at the site, have established landlord/lessee arrangements, or be commercial businesses or non-profits. Through SEU billing management, the subscribers would pay monthly fees based on electricity consumption (e.g. through a PPA contract) rather than directly financing the upfront costs that can stymy potential adoption. This would also provide more equitable access to BTM RE for lower-income residents, who often cannot afford to pay for, or finance, PV and PVS installation costs. Note that we present Figure 5 to illustrate stacking of Energy Options, rather than to recommend a specific portfolio.

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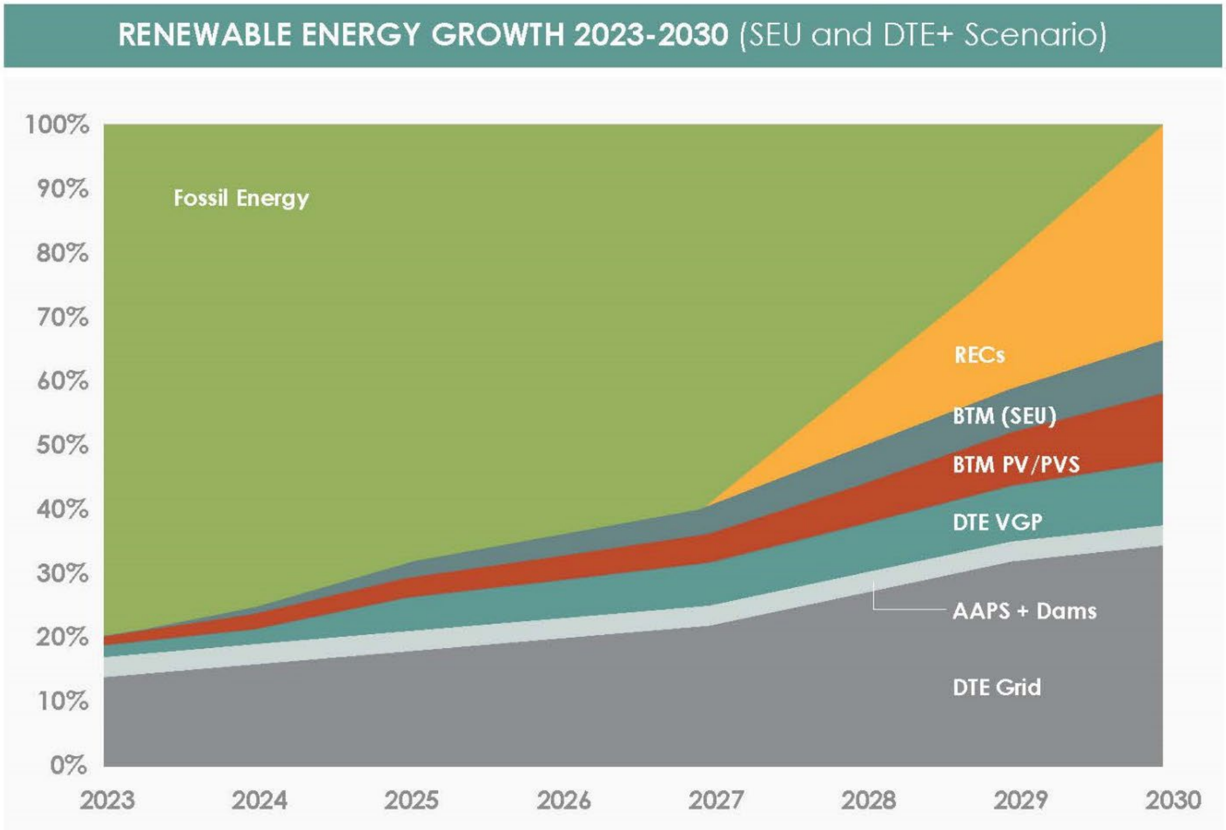
Figure 5: Example SEU scenario integrating many Energy Options to achieve 100% RE by 2030.



There are several paths the SEU can pursue to develop and finance portfolios of Phase 1 (or Phase 2) projects. We considered (i) direct SEU ownership through 100% debt financing, such as a revenue bond or general obligation bond, (ii) third-party ownership where the SEU facilitates development with a company that owns and installs the projects, (iii) potential supporting grant funding from the State of Michigan, federal government, or other organizations, and (iv) any combination of (i) through (iii). For every SEU financing option, we assume the SEU would invoice its subscribers monthly, directly proportional to the amount of electricity generated from the onsite PV system.

We present in Table 4 three Phase 1 deployment portfolios of 10 MW, 50 MW, and 100 MW. The first two portfolios we modeled as 100% debt to convey the potential fiscal impact if the City pursued a new SEU revenue bond or a general obligation bond. For the third portfolio we modeled financing through third-part ownership where the SEU purchases the total portfolio after a 10-year PPA term. We assume that when the SEU is purchasing locally sourced solar power from a PPA, the SEU would still be engaged in subscriber relations and customer billing. Note, the pricing for PVS (integrated battery storage) results in higher portfolio costs that could be billed to subscribers as a higher energy rate, or a PV-only rate coupled with a PVS capacity payment. We assume all costs would be the responsibility of the subscribers, though the City may consider directly paying for battery storage costs as a pathway for resiliency, social equity, and justice.

Table 4: Technical and Financial Description of Three SEU Deployment Scenarios

SEU DEPLOYMENT Three Example Scenarios			
Subscriber Count*	1,250 Subscribers	6,250 Subscribers	12,500 Subscribers
Portfolio Capacity (MW)	10	50	100
PV-Only Capacity (MW)	10	25	50
PVS Capacity (MW)	–	25	50
Overnight Cost ($000)	$ 24,900	$ 151,900	$358,980
1st Finance Structure	100% Debt	100% Debt	10-yr PPA (TPO)
2nd Finance Structure	–	–	Year 10 – 100% Debt
SEU Debt Obligations ($000)	$ 24,900	$ 151,900	$233,000
Deployment Year(s)	2024-2027	2027-2030	2025**
PV-Only Starting PPA Rate	$0.125/kWh	$0.135/kWh	$0.128/kWh
(i) PVS Starting PPA Rate	–	$0.258/kWh	$0.246/kWh
Or (ii) PVS Capacity Payments	–	$82/month	$82/month

* The subscriber count is based on a generalized 8 kW-dc per subscriber. The subscriber count would be higher with residential subscribers that have smaller loads or lower with commercial subscribers' that have larger loads. In addition to the information in the above table, our analysis finds that the IRA expands and amplifies the economic impact of the state policies we modeled.

** 2025 is reference pricing year and deployment would require many years.

The values in SEU Debt Obligations refer to the amount of debt required to fully finance the reference SEU deployments. We assumed this debt is repaid through monthly electricity bills to SEU subscribers over the course of a 22-year PPA term. As shown in the 100 MW portfolio, the upfront capital cost is not inherently required to be financed by debt only. SEU portfolios may be larger or smaller, include PV-only (cheaper), and the years of deployment will impact the overall upfront costs and debt payment obligations.

Overall, we found each of these example scenarios resulted in healthy financial conditions to prove SEU feasibility. We assumed reasonable financial assumptions and note variation in any number of assumptions could result in better or worse financial conditions. The success of any portfolio will rely on:

- Quality development due diligence to establish each candidate subscriber site's ability to install PV.
- Flexibility of financing tools such as timing of debt and interest/repayment obligations.
- A minimum size to achieve economies of scale for equipment and labor, as well as Ann Arbor investment in SEU creation. We assume this economy of scale to be no less than several MWs.

We find the Phase 1 SEU to be feasible for the City, noting that the model is highly scalable to demand. We also note the SEU could start with a small portfolio and grow to more ambitious portfolios over time. We also assess that the Phase 1 SEU would perform very well against the A^2ZERO Energy Criteria and Principles as shown in Table 7, several pages below.

MEU Analysis: Summary

We modeled a potential Ann Arbor Municipal Energy Utility (MEU) as a public utility that owns the electrical distribution infrastructure and sells electricity from third-party generators to its customers who are physically connected to "the grid." When an entity tries to municipalize in this way, it must use a court process to determine the value of the incumbent utility's assets and purchase that infrastructure from the utility. If Ann Arbor were to form a municipal utility, it would likely source electricity through a combination of Power Purchase Agreements (PPAs) and solar PV sited around the city and owned by property owners, the municipal utility itself, or energy developers. Note, the MEU analysis did not integrate modeling BTM PV growth throughout Ann Arbor.

The intent of our Preliminary Municipalization Feasibility Study was to provide initial financial estimates for evaluation by Ann Arbor to help the City determine if it should continue with its investigation of a locally controlled MEU. This Phase I Feasibility Study utilized publicly available data and other information sources to determine potential ranges in cost impacts associated with an MEU for the City.

Uncertainty

Our study assessed what it would cost to operate an MEU and how well it would align with the 2030 A^2ZERO goals. We did not assess the costs and risks the City would likely face before it was able to launch the MEU. Municipalization is a complex legal process that has historically been vigorously opposed by the incumbent utility. We see no reason to expect this would be different in the case of Ann Arbor. Historical experience has been that the process takes many years and involves considerable legal expense.[2] We assess that it would be unlikely that a decision to municipalize could be made, clear all obstacles and prerequisites, and be implemented as early as 2030. We have therefore recommended above that if Ann Arbor determines to proceed to create a municipal utility using distribution assets from DTE, arrangements to reach 100% renewable electricity by 2030 should be made outside of that construct but with defined options to move any generation or power purchase agreements to the municipal utility at the appropriate time.

In addition, estimates of the costs of acquiring DTE assets, developing complementary MEU assets and replacing and maintaining them over time are preliminary, and updated and more thorough analyses would be required for use in formal legal proceedings. As described below, the costs we estimated are "overnight" costs in the immediate future and will change by the time that a municipalization transaction would occur.

Finally, while we assess costs the MEU would incur to assure reliable renewable electricity supply, we do not project costs for improving reliability of electricity delivery – that is, the poles, wires and other assets that carry energy from its generating source to the customers. Our study focuses on identifying sources of renewable energy for Ann Arbor, not on delivery of that energy to customers. Our MEU cost model might improve reliability by replacing distribution system equipment on schedule, whereas much of DTE's equipment now appears to be older than normal service life and presumably less reliable. Any reliability improvements gained from such standard renewal and replacement practices is incidental to

[2] "An Analysis of Municipalization and Related Utility Practices," prepared for the District of Columbia Department of Energy and Environment, September 30, 2017.

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our scope here, and we do not quantify what improvements might be realized. Rigorously projecting costs of improving reliability would require comprehensive, circuit-by-circuit examination of the current system, whereas we collected only a representative sample in our field examination. Similarly, we do not project costs of undergrounding the system, which are highly situational and cannot be rigorously projected with a sampling approach. A Phase 2 municipalization feasibility study, if the City decides to proceed further, could include gathering the distribution system data needed to project costs of improving reliability, including undergrounding.

MEU Capital Costs

We assumed that the MEU would be financed by issuing debt, and that debt service costs would be recovered through the rates MEU customers would pay.

MEU Asset Acquisition Costs

We estimate the cost of acquiring DTE assets would fall within a broad range. The book value of DTE's assets within the City of Ann Arbor can be estimated with rough accuracy, but the methodology that would be used by a court or regulatory body for setting an acquisition price is less clear, because municipalization processes are uncommon nationally and have no recent precedent in Michigan. We developed two types of estimated values for this Study: cost-based estimates and income-based estimates. These two types of estimated values are then used to arrive at overall estimates of the likely range of direct costs to the City of acquiring DTE's distribution system.

The cost-based value estimates were developed from the information obtained from the field investigation and GIS inventories and are based on the Original Cost Less Depreciation of DTE assets to be acquired.

The income-based value estimates were developed from projections of DTE retail rates and MISO wholesale rates, following a methodology for determining a retail-turned-wholesale customer's (e.g., a municipalizing customer's) so-called "Stranded Cost Obligation", as defined by the Federal Energy Regulatory Commission (FERC). We have used this "stranded cost obligation" value to approximate a "going concern" value for DTE's business in the City. Some version of this methodology would almost certainly be applied, but there are few actual examples to demonstrate precisely how. For the high end of what we have called the "FERC Going Concern Valuation Estimate" range, we determined DTE's Revenue Stream Estimate for Ann Arbor, which represents revenue lost to the Company in a municipalization, and subtracted the value DTE could realize by selling electricity on the MISO market instead of to retail customers in Ann Arbor. The difference between these two values is the potential Stranded Cost Obligation associated with the DTE delivery assets and business within the City. For the purposes of this analysis, it is assumed that the high-end Stranded Cost Obligation represents the highest reasonably likely potential valuation of the assets within the City. The high-end Stranded Cost Obligation obtained under the FERC methodology is $1,150,000,000. Likewise, the sum of the cost-based estimate and the low-end SCO obtained under the FERC methodology, which is $281,000,000, represents the lowest reasonably likely potential valuation of the assets within the City.

In sum, we estimate the cost of acquiring DTE's distribution assets and business in Ann Arbor– excluding substations, as discussed next – could plausibly range between $281,000,000 and $1,150,000,000. This is not to say that DTE might not seek a higher valuation or that a court or FERC might not order a lower valuation. These values are simply reasonable estimates derived for planning purposes and may differ from the values DTE or the City may adopt upon further scrutiny should this scenario be pursued.

MEU Additional Capital Costs

As part of establishing the MEU electric system, the City would need to develop transmission assets and associated equipment to take service directly from the regional transmission provider (ITC) and distribute power to the MEU. The City would acquire all the remaining equipment that conveys, transforms, or otherwise manages the power at the distribution level within the City. These new systems would allow current and future DTE customers beyond the City municipal boundaries and served by the same substations as some City residents or businesses to continue to be served by DTE.

We estimate that the MEU would spend $95,360,000 on development of ten new substations and $19,175,000 on new transmission lines to connect the substations to the ITC transmission system. Owners' overhead would add another $34 million, for a total of $149 million in additional capital costs.

We model that the MEU would incur substantial asset replacement costs annually, in line with expected service lives of different asset types. We do not estimate costs to underground wires, upgrade circuits or improve reliability outside of updating infrastructure at time of replacement; these estimates would require much more detailed data on the existing system, which could be undertaken as part of a Phase 2 feasibility study.

MEU Operating Costs

Using the same estimates of load developed based on the A^{2}ZERO 2030 goals and current usage, and projections of the cost of sourcing renewable energy from the MISO regional grid, we were able to estimate year-one power costs for 100% RE for the SEU.

We estimated maintenance and operations costs, and Administrative and General costs, all based on costs reported by DTE in its rate case filings.

MEU Financial Summary

The wide range of our valuation estimates necessarily leads to a wide range of financial outcomes for the MEU in its first year of operation. We find that the revenue required for the MEU could range between 9% less to 38% more than the cost of buying all power from DTE (Table 5). Uncertainty over this range is primarily due to uncertain legal outcomes that would impact costs of municipalization and generally cannot be resolved short of undertaking municipalization.

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Table 5: Year 1 MEU vs DTE Financial Outcomes, low- and high-end estimates

YEAR 1 MEU FINANCIAL OUTCOMES Low & High End Estimates		
Item	Low End Estimate	High End Estimate
Total Annual Sales (kWh)	939,751,000	939,751,000
Ann Arbor MEU Average Rate ($/kWh)	$0.1585	$0.2417
Total Ann Arbor MEU Revenue	$148,993,000	$227,158,000
MEU Power Supply Costs ($)	$78,000,000	$78,000,000
DTE Average Rate in Ann Arbor ($/kWh)	$0.1748	$0.1748
Total DTE Revenue in Ann Arbor	$164,269,000	$164,269,000
DTE in Ann Arbor Power Supply Costs ($)	$85,000,000	$85,000,000
Difference between Ann Arbor MEU and DTE Revenue (Savings)	($15,276,000)	$62,890,000
% Difference	(9%)	38%

In our analysis, over time, MEU financial outcomes improve compared to remaining with DTE. MEU costs remain fairly stable over time, based on projected costs of sourcing renewable energy from the MISO grid, while debt service on costs of initial asset acquisition and construction diminishes. We project, in contrast, that DTE rates will continue to grow steadily: while DTE power costs may stabilize, investments in the distribution system will push rates upwards.

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Table 6: Year 20 MEU vs DTE Financial Outcomes, low- and high-end estimates

YEAR 20 MEU FINANCIAL OUTCOMES Low & High End Estimates		
Item	Low End Estimate	High End Estimate
Total Annual Sales (kWh)	1,745,666,000	1,745,666,000
Ann Arbor MEU Average Rate ($/kWh)	$0.1921	$0.2345
Total Ann Arbor MEU Revenue	$354,068,000	$432,234,000
MEU Power Supply Costs ($)	$215,000,000	$215,000,000
DTE Average Rate in Ann Arbor ($/kWh)	$0.2261	$0.2261
Total DTE Revenue in Ann Arbor	$416,769,000	$416,769,000
DTE in Ann Arbor Power Supply Costs ($)	$133,000,000	$133,000,000
Difference between Ann Arbor MEU and DTE Revenue (Savings)	($62,701,000)	$15,464,000
% Difference	(15%)	4%

Thus, over time, we project that the risk that MEU rates would be higher than DTE rates diminishes.

We do not estimate MEU costs of investing in the distribution system for the purpose of improving reliability; the scope of our study includes reliable power supply but not improving distribution system reliability beyond normal equipment replacement schedules. We also do not assess the cost of increasing distribution system capacity over time, as loads increase per our projections. In contrast, rates we project for DTE include its projected investments in the distribution system, which may anticipate many of these changes.

Costs of distribution system improvements and capacity expansion require significantly more-granular data than were gathered for the purposes of this study and could be addressed in a Phase 2 Feasibility Study if the City deems our findings here sufficiently promising.

Comparative Assessment of Utility Organizational Structures

We can now compare our assessment of the DTE+, SEU and MEU scenarios across several dimensions. Our comparisons are not meant to illuminate a preferred pathway to 100% RE, but to show how technically feasible pathways differ in their deployment of Energy Options, costs and alignment with the A^{2}ZERO Energy Criteria and Principles, to support an informed and inclusive decision-making process.

First, we illustrate side-by-side how Energy Options might be favorably deployed and evolve over time in the DTE+ and MEU scenarios. We then compile our ratings of how the structural options align with the A^{2}ZERO Energy Criteria and Principles to aid comparative analysis.

Energy Option Stacking Varies with Organizational Structure and Over Time

First, we compile the energy stacking pathways from each of our scenarios to illustrate and emphasize that stacking should evolve over time.

Figure 6 depicts all Energy Options applied to the DTE grid. Only the VPRA and Community Solar are considered unavailable at the time of this report, respectively due to an unavailable business model and an unavailable regulatory position. Based on this timeline, the Energy Options available today would remain continuously available for the foreseeable future.

Figure 6: Energy Options available with the DTE grid

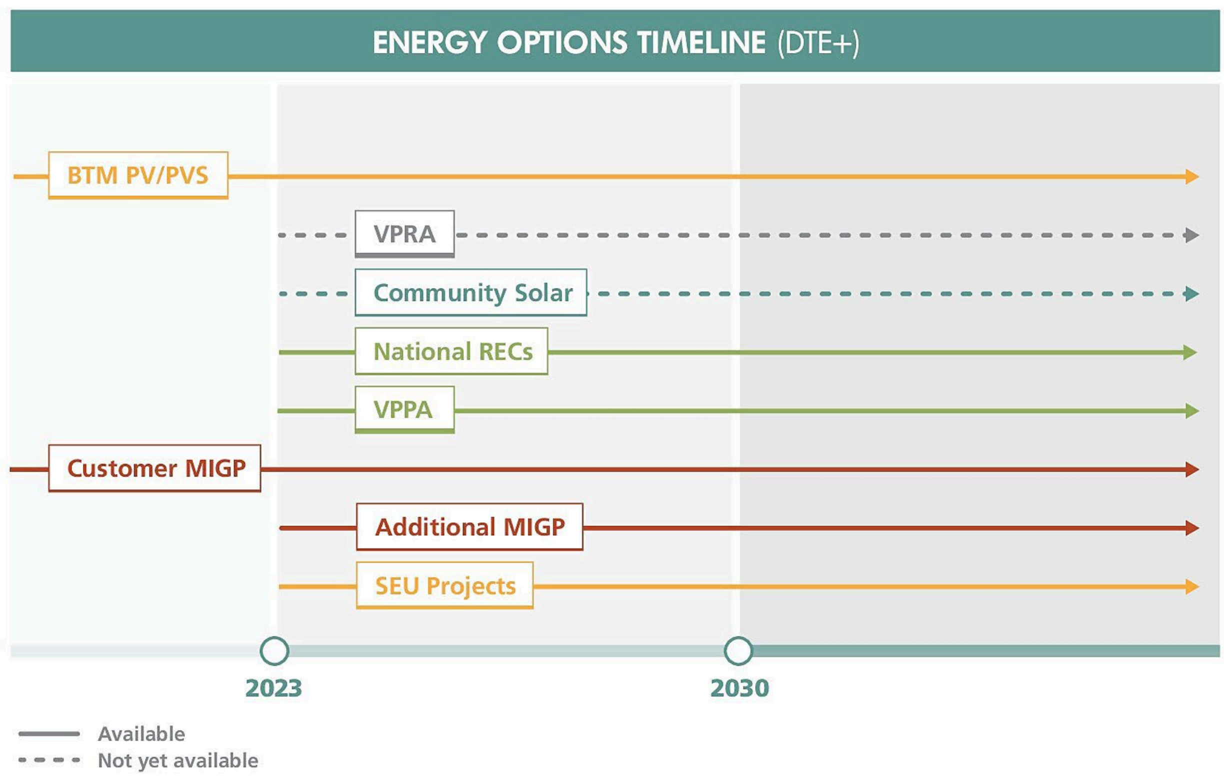
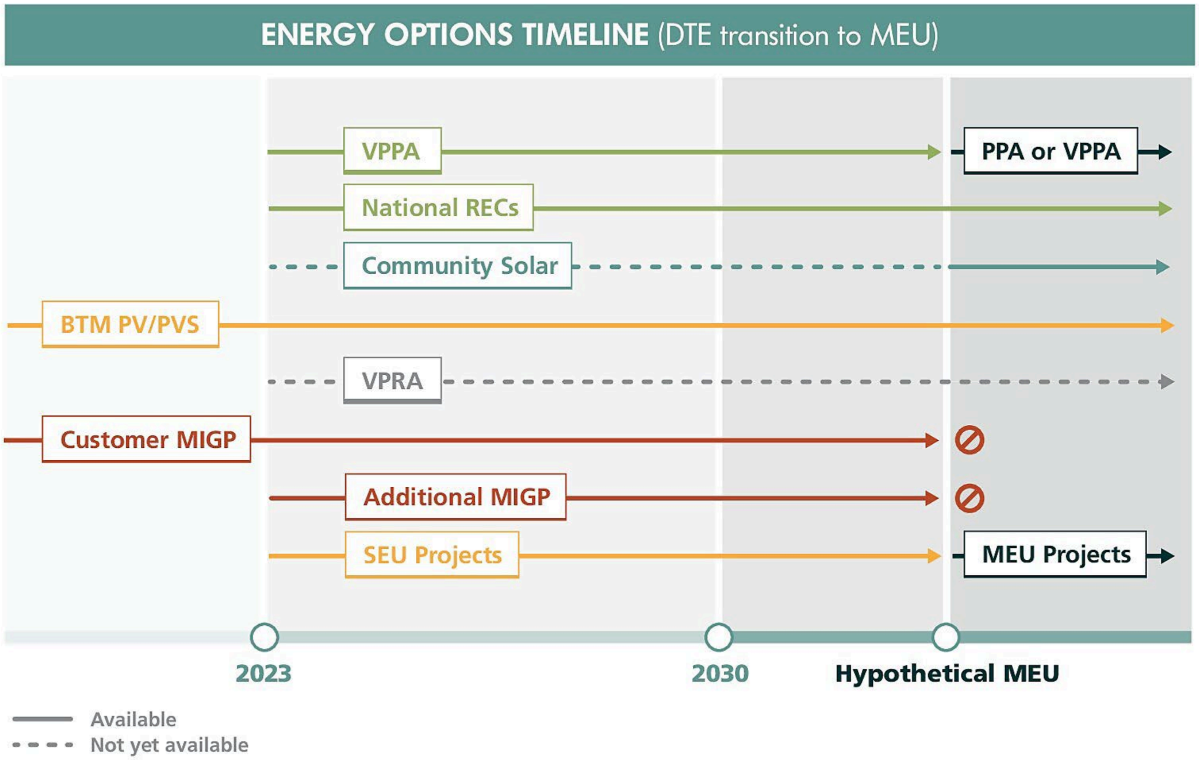


Figure 7 depicts how energy option availability might change over time if the City were to choose to pursue the MEU scenario. All installed BTM PV/PVS would remain operational, and the MEU would assume responsibility for establishing inflow and outflow rates. Any SEU BTM PV/PVS assets would likely transfer management from the SEU to a branch of the MEU. All DTE supported MIGP programs would no longer be applicable so the City would need to secure that RE share from other sources. VPPA contracts might continue in their negotiated form or there could be potential plans to transfer a VPPA into a traditional PPA, highly dependent upon contract status and project location.

Figure 7: Evolution of available Energy Options in DTE transition to MEU Scenario



Alignment of Utility Organizational Options with A²ZERO Energy Criteria and Principles

We evaluate each of the utility organizational structure options against the A²ZERO standards. Unlike all other energy and structure options, our MEU evaluations are not based on a 2030 snapshot. As discussed above, and in greater detail below, we assess that the MEU would be very unlikely to launch before 2030. In our suggested approach to the MEU pathway, therefore, deployment of Energy Options before MEU launch would closely resemble the SEU pathway. For example, the City could start right away to offer third-party financing for BTM PV and PVS, whose assets and programs could be transferred to an MEU if launched or remain within an SEU. Here, instead, we offer our assessment of the MEU's performance in its hypothetical launch year with the Energy Options described above. See Table 7.

Our rating rubric for each Criterion and Principle are explained starting on page 39. Our explanations of how why applied the rating rubric to each organizational structure are detailed on page 102 for DTE, page 127 for the SEU and page 149 for the MEU.

Table 7: Alignment of Utility Organizational Structure Options with A²ZERO Energy Criteria and Principles

ALIGNMENT OF ORGANIZATIONAL STRUCTURES with A²ZERO Energy Criteria

CRITERION	DTE	SEU	MEU (>2030)
Reduce GHG	YES	YES	YES
Additionality	YES	YES	YES
Equity & Justice	GOOD	EXCELLENT	POOR / FAIR

ALIGNMENT OF ORGANIZATIONAL STRUCTURES with A²ZERO Energy Principles

PRINCIPLE	DTE	SEU	MEU (>2030)
Enhance Resilience	POOR	FAIR	POOR
Start Local	FAIR	EXCELLENT	FAIR
Speed	GOOD	FAIR	POOR
Scalable & Transferable	EXCELLENT	GOOD	FAIR
Cost Effective	EXCELLENT	EXCELLENT	POOR / FAIR

Ratings for the MEU come with caveats. First, ratings reflect only the energy modeling we performed, which sources RE entirely from the MISO grid, without stacking in other Energy Options that might improve policy outcomes. We "stacked" energy options only for 2030, and do not foresee the MEU launching by then. We do not dispute that the MEU might deploy more Energy Options than what we model, but our modeling gives us no basis to assign ratings based on that possibility. Second, the MEU ratings are not for 2030, but for some indeterminate future launch year of the MEU. Third, uncertainties about the costs of acquiring DTE assets require us to assign a range of possible ratings to the Equity and Justice and Cost-Effective principles.

It is tempting to interpret Table 7 like a scoresheet, in which case one might conclude that the DTE+ scenario is as favorable to achievement of the A^{2}ZERO Energy Criteria and Principles as the other structures. This approach would not be constructive, for two reasons. One is that the Criteria should receive greater weight than the Principles; also, the Principles are meant to be evaluated qualitatively against each other, not quantitatively toted up. Secondly, these ratings represent snapshots in time (2030 for the DTE+ and SEU scenarios, and some later year for the MEU scenario). We judge that ratings of the SEU and MEU scenarios would likely improve faster than ratings of the DTE+ scenario in the years following these snapshots.

Reliability

Owing to recent, repeated, and lengthy power outages in Ann Arbor, ways to improve reliability increasingly are front and center in the public discussion of the City's energy future. It is important to note that our analysis deals directly only with reliability of energy supply; that is, the ability of various Energy Options to reliably produce the amount of electricity the city will need. We did not directly assess the reliability of the electric distribution system, which has been the source of the growing outage problems in DTE's service territory. At the same time, distribution system issues interact extensively and in complex ways with the renewable electricity focus of our study. Deployment of some of the Energy Options we examine may help improve reliability, while others may prove to be problematic because of the changes they would bring to the distribution system. Ultimately, we did not have data to rigorously assess whether an MEU or SEU would be able to deliver greater distribution reliability than DTE currently provides, at lower cost and/or faster, and in any event this question was beyond the scope of our study. We therefore neither refute nor endorse this possibility.

Recommendations

Our analysis reveals several pathways the City might follow to reach its goal of 100% RE by 2030, differentiated by how they align with the A^{2}ZERO Energy Criteria and Principles. The MEU is promising in its potential alignment with the A^{2}ZERO Energy Criteria and Principles, but our financial analysis indicates it is a risky pathway – without excluding the possibility that it could be cost-competitive with other options. The SEU option is financially feasible, less risky and serves the A^{2}ZERO Energy Criteria and Principles well, but likely has less long-term potential than the MEU to advance the 100% renewable electricity goal; that is, it would continue to rely on energy options provided by DTE. Continued primary reliance on DTE can also achieve 100% RE by 2030 with more-predictable outcomes, but almost certainly would cost the city budget more over time because of the mix of Energy Options it would rely on, and also evaluates somewhat less favorably against the A^{2}ZERO Energy Criteria and Principles.

We suggest that the City authorize a Phase 2 Feasibility Study to characterize more precisely the costs and risks of the MEU approach. Because launch of an MEU is not assured and would likely take many years if it were pursued, the City ought concurrently to consider implementation of an SEU to heighten assurance of meeting its 2030 goals. If subsequent study supported launch of an MEU, when the time came the SEU assets and programs could be transferred over; if not, the SEU could continue apace. In short, we see development of an SEU as consistent with, and advantageous to, the longer-term

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development of an MEU. If the City embraces that concept, the question becomes how to start stacking the Energy Options to attain the 2030 goal while also laying groundwork for an MEU.

Although behind-the-meter resources and neighborhood solar are favored by many of the A^{2}ZERO Energy Criteria and Principles, the long-term potential for these renewable resources falls short of the City's total electricity requirements, and the pace at which these can be developed will likely be gradual because they require individual decisions by many property owners. It is therefore necessary that the City meet the goal of 100% renewable generation by 2030 using a significant amount of utility-scale renewables that are remote from the City.

However, all utility-scale generation delivers power to the transmission grid where it is physically integrated with power flows from all other utility-scale generation on the same grid. In this region, all utility-scale power is sold into a wholesale market from which all power for delivery to customers is purchased by the utility that distributes power to them. Consequently, renewable power loses identity in the power markets. Also importantly, only a utility can purchase actual power from the transmission system and if Ann Arbor purchases power from a specific wind farm or solar system connected to the transmission grid, all it can do with that power is sell it into the wholesale market.

To facilitate tracking the production and use of renewable generation, markets have been created for renewable energy credits (RECs) that can be purchased separately from the actual power so that the buyer can claim exclusive rights to the renewable characteristics of the power. The purchase of RECs provides an economic incentive for renewable generation by adding revenue on top of the energy and capacity sales that the facility can make. Each REC corresponds to 1 megawatt-hour (MWh) of power generated from a renewable resource. Ann Arbor can reasonably meet its 100% RE goal by purchasing RECs to supplement RE resources provided by DTE and PV resources installed in or by the City. Since every other source of renewable energy that the City could use is either available only in small quantities relative to the City's requirements, or will be slow to develop, or both, the City can meet its 100% RE goal only by significant purchases of RECs produced from utility-scale renewable generation.

RECs vary in quality with respect to the City's principles. RECs sourced from existing renewable energy facilities will not provide additionality. RECs sourced from Texas do not provide benefits local to Ann Arbor. In general, higher quality RECs will be costlier and require longer lead times.

In short, we recommend that the City meet its initial requirements for renewable generation of electricity by purchasing RECs, with attention to the quality of those RECs, with some purchases being for recurring purchases over long periods of time and others being for short periods so that they can be displaced through other Energy Options that will contribute more to load after 2030. In the evaluation of other strategies, over time, the avoided cost of purchased RECs will be one of the quantifiable benefits of the other strategies.

Our analysis shows that Ann Arbor has viable, if ambitious, pathways to reach its goal of 100% renewable electricity by 2030. The benefits, costs and risks of those pathways change over time and create changing tradeoffs among the A^{2}ZERO Energy Criteria and Principles. We suggest here a strategy that would allow the City to reduce the uncertainties of one potential pathway, while moving ahead now with a strategy that keeps Ann Arbor on track to 100% RE in 2030 without foreclosing other options.